Management's Discussion and Analysis

May 10, 2012

This Management's Discussion and Analysis ("**MD&A**") of financial condition and results of operations for Eagle Energy Trust (the "**Trust**"), dated May 10, 2012, should be read in conjunction with the unaudited interim condensed consolidated financial statements and accompanying notes for the three months ended March 31, 2012 ("**Interim Financial Statements**") and the Trust's audited consolidated financial statements and accompanying notes and related MD&A for the year ended December 31, 2011 and the Trust's Annual Information Form dated March 22, 2012 ("**AIF**"), which are available online at www.sedar.com and on the Trust's website at www.eagleenergytrust.com.

The Interim Financial Statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**"). Items included in the financial statements of each of the Trust's subsidiaries are measured using the currency of the primary economic environment in which the entity operates (the "**functional currency**"). The Interim Financial Statements are presented in Canadian dollars, which is the functional and presentation currency of the Trust.

Figures within this MD&A are presented in Canadian dollars unless otherwise indicated.

This MD&A contains information that is forward looking. Investors should read the "Note about Forward Looking Statements" section at the end of this MD&A.

Non-IFRS financial measures

Statements throughout this MD&A make reference to the terms "field netback" and "funds flow from operations" which are non-IFRS financial measures that do not have any standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that "field netback" and "funds flow from operations" provide useful information to investors and management since such measures reflect the quality of production, the level of profitability, the ability to drive growth through the funding of future capital expenditures and the sustainability of distributions to unitholders. Funds flow from operations is calculated before changes in non-cash working capital. Field netback is calculated by subtracting royalties and operating costs from revenues. See the "Non-IFRS financial measures" section of this MD&A for a reconciliation of funds flow from operations and field netback to income for the period, the most directly comparable measure in the Trust's audited annual consolidated financial statements. Other financial data has been prepared in accordance with IFRS.

Overview of the Trust

The Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. The Trust's strategy is to invest in operating subsidiaries that will acquire onshore petroleum reserves and production with unexploited low risk development potential, located in certain regions of the U.S., and to pay out a portion of available cash to unitholders of the Trust on a monthly basis. The Trust provides investors with a publicly traded, petroleum focused, distribution producing investment, with favourable tax treatment relative to taxable Canadian corporations.

The Trust was formed on July 20, 2010, but did not commence active operations until November 24, 2010, the date of its initial public offering. During November and December 2010, the Trust raised $149.5 million, at an offering price of $10.00 per trust unit, through an initial public offering. Concurrent with closing its initial public offering the Trust acquired, indirectly through its wholly-owned subsidiary, an average 73% interest in the Salt Flat Field, a light oil property located in south central Texas, for $127.1 million. Consideration consisted of cash and 2,000,000 trust units valued at $20 million.

Throughout this MD&A, Eagle Energy Trust and its subsidiaries are collectively referred to as "the Trust" for purposes of convenience. In addition, references to the results of operations refer to operations of the Trust's U.S. subsidiary, Eagle Energy Acquisitions LP ("**Eagle**").

Highlights for the three months ended March 31, 2012

- Two (1.6 net) horizontal sidetrack re-entry oil wells drilled during the period with one (0.8 net) tied in late in March.
- First quarter average working interest sales volumes of 2,169 barrels of oil per day.
- First quarter funds flow from operations of $9.1 million ($46.20 per barrel or $0.50 per unit), up approximately 75% from $5.2 million in the first quarter of 2011 ($45.47 per barrel or $0.29 per unit).
- First quarter field netbacks of $54.36 (2011 first quarter average - $51.00) per barrel.
- No bank debt, an expanded $US 31.0 million credit facility (based on the 2011 independent reserves evaluation).
- 2012 unitholder distributions of $0.26 per unit for the quarter ($0.0875 per unit per month).

Acquisition of producing light oil assets in the Permian Basin, Texas, bought deal trust unit financing and increase in credit facility

On May 3, 2012, the Trust announced it had signed a purchase and sale agreement to acquire, indirectly through its wholly-owned subsidiary, 92.5% of the seller's 99% interest in certain Permian Basin oil and natural gas properties and related assets located in the State of Texas for a purchase price of US$113,369,688, subject to closing adjustments. In connection with this, the Trust has filed a preliminary short form prospectus qualifying the distribution of 7,730,000 trust units at a price of $11.00 per unit. The Trust intends to use the net proceeds of the offering, plus an advance of approximately US$28.8 million under its credit facility and approximately US$5.5 million of working capital to fund the acquisition. In addition, the Trust's lender has approved an increase in the borrowing base of the credit facility to US$48.5 million from US$31 million. The amendment to the credit facility will be in place prior to completion of the acquisition. Refer to the "Outlook" section of this MD&A.

Results of operations

Revenue

	Three Months Ended March 31, 2012	**Three Months Ended March 31, 2011**
Sales volumes – bbls per day (100% light oil)	**2,169**	**1,269**

	Three Months Ended March 31, 2012		**Three Months Ended March 31, 2011**	
	$	**/bbl**	**$**	**/bbl**
Benchmark WTI ($US)		102.84		93.92
Realized sales price ($US)		97.49		87.30
Differential to benchmark ($US)	$	5.35	$	6.62
Oil sales before royalties		97.16		86.39
Royalties		(26.49)		(23.90)
Revenue	**$**	**70.67**	**$**	**62.49**

There is a quality differential between the benchmark West Texas Intermediate ("**WTI**") price and the sales price realized by Eagle. Eagle has secured transportation and marketing agreements and continues to monitor these differentials to ensure that volumes will be marketed at differentials to the WTI posted price that are deemed by management to be optimal.

The benchmark WTI price increased 9.5% from first quarter 2011, with $US realized prices and Canadian dollar realized prices increasing by a commensurate amount. Not included in this figure is a realized loss on commodity contracts of $255,983 ($1.30 per barrel) for the year to date. See *Realized and unrealized risk management gain/loss.*

Working interest sales volumes for the three months ended March 31, 2012 averaged 2,169 bbls per day (100% light oil), a 71% increase from March 31, 2011 levels. First quarter 2012 volumes benefitted from 25 (20.0 net) additional horizontal oils wells being tied in and brought on stream since the first quarter of 2011.

The overall royalty rate of approximately 27% was consistent with prior periods.

Cost of sales

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
	$	**/bbl**	**$**	**/bbl**
Transportation		1.98		1.97
Other operating costs		14.33		9.51
	$	16.31	$	11.49
Depreciation, depletion and amortization		25.73		25.30
Cost of sales	**$**	**42.04**	**$**	**36.79**

Fuel and power, utilities and equipment rentals (generators) account for 53% of operating costs during first quarter 2012 vs. 21% for the three months ended March 31, 2011. First quarter 2012 per barrel operating costs include $6.01 (March 31, 2011 - $2.42) per barrel relating to increased utility and power consumption attributed to wells brought on stream in late 2011. The use of diesel generators to produce these wells is temporary, pending permanent power installation. Generators have now been removed from four leases and surveying and procurement activities are underway for the northern leg of the power trunk line which should result in the remaining generators being removed by early in the third quarter.

The depletion, depreciation, and amortization provision for the period ended March 31, 2012 was based on proved plus probable reserves, including the future development costs associated with those reserves, as found in the year end 2011 reserves evaluation report prepared by the Trust's independent reserves evaluators.

Field netback

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
($000's)	**$**	**$ /bbl**	**$**	**$ /bbl**
Oil sales before royalties	19,175	97.16	9,864	86.39
Royalties	(5,227)	(26.49)	(2,729)	(23.90)
Transportation	(391)	(1.98)	(225)	(1.97)
Other operating costs	(2,828)	(14.33)	(1,086)	(9.51)
Field netback	**$ 10,729**	**$ 54.36**	**$ 5,824**	**$ 51.00**
Sales volumes (bbls per day)		**2,169**		**1,269**

During the quarter, benchmark WTI averaged $US 102.84 per barrel and the Trust realized a field netback of $54.36 per barrel.

Field netback is a non-IFRS financial measure. See "Non-IFRS financial measures".

Realized and unrealized risk management gain/loss

As part of the Trust's ongoing strategy to mitigate the effects of fluctuating prices on a portion of its production, the following contracts have been put in place: (i) a costless collar for 200 bbls of oil per day with a February 2011 through January 2012 term at a floor of $US 85.00 per barrel and a ceiling of $US 100.00 per barrel; (ii) a costless collar for 200 bbls of oil per day with a May 2011 through April 2012 term at a floor of $US 88.00 per barrel and a ceiling of $US 107.55 per barrel; (iii) a fixed contract to sell 100 bbls of oil per day with a May 2011 through April 2012 term at a price of $US 101.00 per barrel; (iv) a fixed contract to sell 200 bbls of oil per day with a November 2011 through October

2012 term at a price of $US 91.00 per barrel; (v) a costless collar for 500 bbls of oil per day with a January 2012 through December 2012 term at a floor of $US 92.00 per barrel and a ceiling of $US 105.00 per barrel; (vi) a costless collar for 300 bbls of oil per day with a May 2012 through April 2013 term at a floor of $US 95.00 per barrel and a ceiling of $US 108.25 per barrel; (vii) a fixed contract to sell 200 bbls of oil per day with a January 2013 through April 2013 term and 500 bbls of oil per day with a May 2013 through December 2013 term, at a price of $US103.45 per barrel; and (viii) a fixed contract to sell 400 bbls of oil per day with a January 2014 through December 2014 term, at a price of $US98.00 per barrel.

A sharply stronger forward commodity pricing environment caused a decrease in the future value of these contracts and an increase in the liability position during the first quarter. Although the Trust currently has no intention of unwinding the contracts that are in place, it is required to calculate and record, using a mark-to-market valuation, the fair value of the remaining term of the contracts at the end of each reporting period. As a result, the Trust recognized a $930,045 unrealized risk management loss and realized a $255,983 risk management loss for the quarter.

Administrative expenses

Total administrative expenses for the first quarter were $1,361,415, approximately $235,000, or 21%, above first quarter 2011 levels. This increase primarily relates to additional staffing and the associated benefits, training and recruiting costs. The Trust assumed operatorship of the Salt Flat Field during 2011 and required additional engineering, field and accounting staff to assist with full cycle development of the Salt Flat Field, acceleration of the strategic focus on potential new acquisitions and management of planned activities. A large portion of administrative expenses are fixed in nature, so the production additions that occurred in the latter portion of 2011 resulted in per barrel general and administrative during first quarter 2012 to be 29% lower than first quarter 2011.

Unit-based compensation

Non-cash unit-based compensation expense of $4,004,885 ($2,774,856 for the three months ended March 31, 2011) was recorded during the first quarter as an additional liability. The components of the expense related to (i) $2,167,972 for the estimated fair value of escrowed units and restricted unit rights that were previously issued upon surrender of performance options ($1,458,983 for March 31, 2011); (ii) $1,594,344 for the estimated fair value of options granted under the option plan ($1,315,873 for March 31, 2011); and (iii) $242,568 for the estimated fair value of phantom unit rights granted under the phantom unit rights plan ($nil for March 31, 2011).

The dollar amount of unit-based compensation expense does not represent cash paid by the Trust. The Trust is, however, required to re-determine the fair value of the liability relating to the escrowed units, restricted unit rights, options and phantom unit rights at the end of each reporting period and record any changes in fair value through the income statement. The actual value realized by holders of the awards will depend on the price the escrowed units are eventually sold for, the accumulated distributions actually paid by the Trust, the actual year over year price appreciation of the units, the actual price of the units, the actual exercise price of the options at the time the options are exercised and the actual payments pursuant to the phantom unit rights plan.

From one reporting period to the next, changes in the closing price of the units, accumulated distributions and expected future unit price volatility will increase or decrease the fair values that are derived using the Black-Scholes valuation model and cause corresponding swings in the amount recorded in the income statement. The increase in the liability and associated expense from March 31, 2011 to March 31, 2012 was primarily due to: (i) the passage of time, since unit-based compensation expense is recorded in the income statement over the vesting periods of the awards; (ii) an increase in year over year volatility assumption of Eagle’s units from 33% to 35%; and (iii) the implementation of the Phantom Unit Rights (PUR) plan for United States based employees effective June 14, 2011.

Tax horizon

The tax horizon, as determined from a full cycle corporate model incorporating cash flows from the year end reserves evaluation report plus all applicable U.S. deductions, indicates that no material U.S. taxes are expected to be payable in respect of income attributable to the Salt Flat interest for several years. Management expects to extend this period through continued capital investments and additional acquisitions in the U.S. as the Trust executes its business plan. No taxes are expected to be payable by the Trust in Canada because the Trust will distribute its full taxable income each year to unitholders and will not be a SIFT trust, as defined under the *Income Tax Act* (Canada), provided that the Trust complies at all times with the investment restrictions as set forth in the Trust Indenture.

Summary of quarterly results

	Q1/2012	Q4/2011	Q3/2011	Q2/2011	Q1/2011	YTD/2010[1]
($000's except for bbls per day and per unit amounts)						
Sales volumes – bbls per day (100% light oil)	2,169	2,023	995	1,214	1,269	726
Revenue, net of royalties	13,947	11,798	5,533	7,305	7,135	1,366
per bbl	70.67	63.40	60.42	66.10	62.49	60.72
Funds flow from operations	9,118	7,199	2,432	5,029	5,192	(288)
per bbl	46.20	38.69	26.55	45.52	45.47	(2.80)
per unit – basic & diluted	0.50	0.39	0.14	0.28	0.29	(0.07)
Income (loss)	(952)	(1,426)	421	1,703	(1,911)	(3,212)
per unit – basic & diluted	(0.05)	(0.08)	0.02	0.10	(0.11)	(0.81)
Cash distributions declared	5,024	4,936	4,848	4,775	4,728	1,916
per issued unit	0.2625	0.2625	0.2625	0.2625	0.2625	0.1064
Current assets	16,447	13,385	14,121	20,067	27,920	33,103
Current liabilities	20,319	16,557	12,023	7,299	11,712	9,062
Total assets	156,477	158,885	164,480	150,351	154,138	159,868
Total non-current liabilities	489	503	2,671	4,496	2,893	725
Unitholders' equity	135,669	141,826	149,786	138,556	139,532	150,081
Units outstanding for accounting purposes	18,847[2]	18,544[2]	18,175[2]	17,894[2]	17,624[2]	17,624[1,2]
Units issued	19,234	18,931	18,562	18,282	18,012	18,012

Note:

(1) The Trust was formed on July 20, 2010, but did not commence active operations until November 24, 2010, the date of its initial public offering.

(2) Units outstanding for accounting purposes exclude 387,500 units issued due to the performance conditions that have to be met to enable such units to be released from escrow.

With the exception of the third quarter of 2011, which had approximately 328 barrels per day of oil temporarily shut in due to delays in obtaining Texas Commission on Environmental Quality permits, production has grown commensurate with well tie-ins. During the first quarter of 2012, one (0.8 net) oil well was tied in late in March.

Funds flow from operations grows as sales volumes increase, and on a per-barrel basis, will decline when volumes decline, as they did in the third quarter of 2011. This is because certain expenses tend to be more fixed in nature, such as general and administrative expenses, and do not decrease as sales volumes decrease.

Income (loss) on a quarterly basis often does not move directionally nor by the same amount as movements in funds flow from operations. This is primarily due to items of a non-cash nature that factor into the calculation of income (loss), which are required to be fair valued at each quarter end, such as unit-based compensation or the mark-to-market value of existing commodity pricing contracts.

Liquidity and capital resources

Generally, three sources of funding are available to the Trust: (i) internally generated funds flow from operations; (ii) debt financing, when appropriate; and (iii) the issuance of additional units, if available on favourable terms, including proceeds obtained from the Trust's distribution re-investment programs.

Management's objective is to maintain a bank debt to cash flow ratio below 1.5 times.

The Trust has filed a preliminary short form prospectus qualifying the distribution of 7,730,000 trust units at a price of $11.00 per unit. In addition, the Trust's lender has approved an increase in the borrowing base of the credit facility to US$48.5 million from US$31 million. The amendment to the credit facility will be in place prior to completion of the acquisition. The Trust believes that its expected funds flow from operations and the undrawn credit facility will be sufficient to fund its planned capital investment program, enable it to meet all current and expected financial requirements and maintain unitholder distributions. Refer to the “Outlook” section for a discussion of the Trust’s future plans. Other than the items noted in the “Commitments” section of this MD&A, capital spending is discretionary.

Subsequent to quarter end, the Trust has filed a preliminary short form prospectus, refer the section titled “Acquisition of Producing Light Oil Assets in the Permian Basin, Texas and Bought Deal Trust Unit Financing” on page 2 of this MD&A.

Funds flow from operations

The following table summarizes funds flow from operations on a per barrel basis:

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
($000’s)	**$**	**$ /bbl**	**$**	**$ /bbl**
Field netback	10,729	54.36	5,824	51.00
Administrative expenses (1)	(1,338)	(6.78)	(1,127)	(9.87)
Realized risk management gain (loss)	(256)	(1.30)	(18)	(0.16)
Finance expense	(27)	(0.13)	(5)	(0.04)
Realized foreign exchange gain(2)	10	0.05	518	4.54
Funds flow from operations	**$** 9,118	**$** 46.20	**$** 5,192	**$** 45.47

Notes:

(1) On a go-forward basis, per barrel administrative costs are expected to trend lower due to increased production.

(2) This represents settled foreign currency transactions related to operating activities.

Funds flow from operations is a non-IFRS financial measure. See “Non-IFRS financial measures”.

Credit facility

As of March 31, 2012, the Trust had no debt and had available a $US 31 million credit facility, indirectly through its U.S. subsidiary, with a U.S. affiliate of a Canadian chartered bank.

Working capital

At March 31, 2012, the Trust had a working capital deficiency of $3.9 million (which becomes an $8.6 million surplus when the non-cash current portion of unit-based compensation is excluded) and no amounts drawn on its bank credit facility described above.

Unitholders’ equity

All issuances of Trust capital were issued pursuant to the distribution reinvestment plans as detailed below.

As a result of its Premium Distribution™ and Distribution Reinvestment Plan, the Trust received proceeds resulting from the issuance of units from treasury to those unitholders who have opted to participate in the Plan. For the three months ended March 31, 2012, 303,377 units were issued for total proceeds of approximately $3.1 million at an average price of $10.24 per unit.

Management may also seek to issue additional units in the future to provide sufficient capital to fund growth, including acquisition opportunities. Subsequent to the end of the quarter, the Trust filed a preliminary short form prospectus qualifying the distribution of 7,730,000 trust units at a price of $11.00 per unit. Refer to the “Outlook” section for a discussion of the Trust’s future plans.

Distributions and outstanding unit data

The Trust pays monthly distributions to unitholders at the discretion of the Board of Directors. Distributions paid in the first quarter (for the December 2011, and January and February 2012 record dates) totaled approximately $5.0 million.

At March 31, 2012, the Trust had issued 19,234,476 units. For purposes of the March 31, 2012 consolidated financial statements, 18,846,976 units were shown as outstanding. The 387,500 difference relates to units previously issued on the surrender of performance options that are excluded from financial statement figures because IFRS principles exclude units that require a performance condition be met before being released from escrow. Distributions are paid on the units while they are in escrow.

As at the date of this MD&A, 19,338,004 units are issued and 1,706,000 options are outstanding.

Capital expenditures

Capital spending during the first quarter of 2012 and for the first quarter of 2011 was as follows:

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
($000's)	$	$
Exploration and evaluation[1]	83	149
Acquisition of the Salt Flat Field interest (adjustment)	-	(119)
Intangible drilling and completions[2]	(280)	4,820
Well equipment and facilities	2,755	633
Other	81	28
	$ 2,639	$ 5,511

Note:

(1) Exploration and evaluation expenditures relate to amounts spent on land to which no proven reserves are yet assigned.

(2) Lower than expected costs relating to 2011 capital activity resulted in a net credit in first quarter 2012 intangible drilling and completion costs.

During the first quarter, two (1.6 net) horizontal sidetrack re-entry oil wells were drilled with one (0.8 net) tied in late in March.

Related infrastructure investment and construction of a power trunk line continued throughout the first quarter with the objective to remove all generators currently in use as soon as possible to reduce operating costs. Generators have now been removed from four leases and surveying and procurement activities are underway for the northern leg of the power trunk line which should result in the remaining generators being removed by early in the third quarter.

Commitments

The Trust has committed to future payments as follows:

($000's)	Total $	Less than 1 year	1 – 3 years	After 3 years
Operating leases [1][2][3]	211	143	68	-
Purchase obligation [4][6]	878	878	-	-
Settlement agreement [5]	60	60	-	-
Total contractual obligations	**$ 1,149**	**$ 1,081**	**$ 68**	**-**

Notes:

(1) Calgary, Alberta office lease: The initial term of the sub-lease agreement was for 6 months from January 1, 2011 until June 30, 2011. On July 25, 2011, the sub-lease agreement was renewed for an additional 6 month period from August 1, 2011 to January 31, 2012 under the same terms as before with the exception of a monthly rent rate of $8,500. Thereafter, the agreement will automatically roll over on a monthly basis, unless either party serves a 30 day notice of termination. Therefore, the agreement is cancellable at the end of the term if notice is provided. Future minimum lease payments during the six month term of the sub-lease were $51,000, with $nil remaining as at March 31, 2012.

(2) Houston, Texas office lease: The sub-lease agreement was entered into on April 1, 2011, and has an approximate 30 month term from April 7, 2011 through September 30, 2013. Future minimum lease payments during the term of the sub-lease approximate $US 338,400, with 18 months and approximately $US 203,000 remaining at March 31, 2012. In $CA the remaining future minimum lease payments approximate $202,600 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9975.

(3) Luling, Texas office lease: The sub-lease agreement was entered into on August 15, 2011, and has an approximate 12 month term from August 15, 2011 through August 31, 2012. Future minimum payments during the term of the sub-lease are $US 20,600, with $US 8,300 remaining at March 31, 2012. In $CA, the remaining future minimum lease payments approximate $8,200 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9975.

(4) The Trust, through its operations in the Salt Flat Field, entered into a nine well drilling rig commitment agreement effective December 15, 2011. At March 31, 2012, no wells had been drilled under the agreement. Future minimum payments are estimated to be approximately $US 1,100,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 880,000. In $CA the net future commitment approximates $878,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9975.

(5) The Trust, through its operations in the Salt Flat Field, signed a settlement agreement with a third party relating to damages in the producing formation of nearby wells. Future costs are estimated to be $US 75,000, which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 60,000. In $CA the net future commitment approximates $59,900 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9975.

Transactions with related parties

Key management personnel

Key management personnel consist of the Chief Executive Officer (CEO), Chief Operating Officer (COO), Chief Financial Officer (CFO), and the Directors.

Intercompany transactions

There are certain intercompany transactions among the subsidiaries comprising the consolidated financial statements of the Trust. These transactions have been eliminated upon consolidation.

Head office lease in Calgary, Alberta

The Trust sub-leases office space along with furniture and equipment from a company of which a director of the administrator of the Trust is the President and Chief Operating Officer. The terms of the agreement are recorded at the exchange amount. The monthly rent rate is $8,500, which approximates market value. Refer to “Commitments” section of this MD&A. No amounts were owing to this related party as at March 31, 2012. For the three months ended March 31, 2012 administrative expenses included $25,500 (March 31, 2011 - $24,000) for amounts billed from this related party.

Critical accounting estimates

There have been no changes to the Trust’s critical accounting estimates and judgments in the first quarter of 2012. Further information about the Trust’s critical accounting estimates and judgments can be found in the notes to the Consolidated Financial Statements and MD&A for the year ended December 31, 2011.

Risk management

For a more detailed description of the risks and uncertainties faced by the Trust, refer to the Trust’s Annual Information Form. The Trust’s activities expose it to a variety of financial risks that arise as a result of its exploitation, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

Credit risk is the risk of financial loss to the Trust if a joint venture partner, customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Trust’s receivables from its product marketer and joint venture partners. Receivables from the Trust’s marketer are normally collected in the month following production. The Trust’s policy to mitigate credit risk associated with these balances is to establish marketing relationships with reputable purchasers with good credit and, over time, to spread this risk among as many different marketers as is reasonably feasible. Joint venture receivables are with customers in the oil and gas industry and are subject to normal industry credit risks. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. In certain circumstances, the Trust may request an operating advance or cash call a partner in advance of expenditures being incurred.

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they fall due. At March 31, 2012, the Trust had a working capital deficiency of $3.9 million (which becomes an $8.6 million surplus when the non-cash current portion of unit-based compensation is excluded) and no amounts drawn on its $US 31 million bank credit facility. The approach to managing liquidity is to ensure, as far as possible, that the Trust will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Trust’s reputation. To better manage its liquidity risk, the Trust prepares an annual capital expenditure budget, which is regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures (“**AFEs**”) on both operated and non-operated projects to manage capital expenditures. The Trust attempts to match its payment cycle with the collection of its oil revenue each month.

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Trust’s income or the value of the financial instruments of the Trust. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil are impacted by various factors, including the exchange rates between the Canadian and United States dollar, but also world economic events that dictate the levels of supply and demand. The Trust may enter into certain financial derivative instruments periodically to economically hedge some oil sales through the use of various financial derivative forward sales contracts and physical sales contracts. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. It is the policy of the Trust to not hedge more than 50% of its near-term net production. As at the date of this MD&A, the Trust has entered into contracts to mitigate the effect of commodity price fluctuations in the coming 12 months. Refer to the “Realized and unrealized risk management gain” section of this MD&A.

Foreign exchange risk is the risk that future cash flows will fluctuate as a result of changes in market foreign exchange rates. The Trust’s operating cash flows are generated in US dollars and distributions are declared in Canadian dollars. As a consequence, there is an element of foreign exchange risk to the Trust. The Trust’s treasury management function is responsible for managing funding requirements and investments, which include banking and cash flow management. Prices for oil are determined in global markets and denominated in US dollars. Generally, an increase in the value of the $CA as compared to the $US will reduce the prices received by the Trust for its petroleum and natural gas sales, but will also reduce the operating expenses associated with those sales as well as reduce the price paid by the subsidiary of the Trust for future asset acquisitions.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust may be exposed to interest rate risk at both fixed and variable rates as it borrows funds. There have been no draws against the credit facility during the quarter ended March 31, 2012 and no amounts were outstanding under the credit facility as of March 31, 2011. The Trust therefore had no interest rate risk, and as a result, did not hedge against any interest rate exposures.

Outlook

This outlook section is intended to provide unitholders with information about Eagle’s expectations as at the date hereof for production and capital expenditures for 2012 and readers are cautioned that the information may not be appropriate for any other purpose. This information constitutes forward-looking information. Readers should note the assumptions, risks and discussion under "Note about forward-looking statements".

The Trust has not issued revised guidance to incorporate the *Acquisition of producing light oil assets in the Permian Basin, Texas,* discussed below. 2012 guidance thus remains unchanged, with a capital budget of US$14 million (excluding any corporate and property acquisitions, which are evaluated separately on their own merits), average working interest production of 2,600 barrels of oil per day, funds flow from operations of $40 million at $88 WTI pricing, an estimated payout ratio of 50% at $88 WTI pricing and operating costs ranging from $11.25 to $11.75 per barrel. These figures are consistent with the Trust's guidance provided in its annual MD&A for the year ended December 31, 2011.

Acquisition of producing light oil assets in the Permian Basin, Texas

In keeping with its stated growth strategy, the Trust continues to actively pursue opportunities to acquire additional producing properties in the United States.

On May 3, 2012, the Trust announced that its operating subsidiary has entered into a binding agreement to acquire 92.5% of the seller's 99% interest (an effective 91.7% interest) in producing petroleum properties in the Permian Basin, located near Midland, Texas (the “**Acquired Assets**”), for a purchase price of US$113.4 million, subject to closing adjustments (the “**Acquisition**”).

The Acquired Assets consist of 3,175 gross (2,937 net) acres of land with total estimated proved plus probable reserves of approximately 10.2 million barrels of oil equivalent (“boe”) as at March 31, 2012. Working interest production from the Acquired Assets in March 2012 was approximately 600 boe per day (“boe/d”), which Eagle expects to increase to approximately 1,000 boe/d by the end of 2012 through a planned drilling program. Oil and natural gas liquids represent approximately 88% of the total proved plus probable reserves, and natural gas represents the remaining 12%.

The Acquired Assets have a long reserve life and are expected to generate long term sustainable cash flow, which complements the strong near-term cash flow of Eagle's existing assets in the Salt Flat Field. Eagle and the seller have secured a drilling rig and completion services for the Acquired Assets. Eagle expects this will ensure that the capital program will be executed as planned. Eagle anticipates increasing production in the Acquired Assets by drilling at least ten wells per year.

The Acquisition has the following attributes:

- 91.7% working interest in 3,175 gross (2,937 net) acres of lands.
- Working interest in 31 gross (28.4 net) producing wells and three gross (2.76 net) non-producing wells and one gross (0.92 net) salt water disposal well.
- The Acquired Assets will be 100% operated by Eagle following a short transition period from the current operator.
- Current working interest production of approximately 600 boe/d, which Eagle anticipates it will increase to approximately 1,000 boe/d by year end.
- For 2011, the field netback for the Acquired Assets was US$46.60 per boe.
- Estimated reserves of approximately 8.1 million boe proved and 10.2 million boe proved plus probable, as of March 31, 2012, based on an independent reserves evaluation report prepared by Netherland, Sewell and Associates Inc.
- The reserves are being acquired at US$14.00 per proved boe and US$11.09 per proved plus probable boe (before giving effect to future development costs).
- Oil and natural gas liquids represent approximately 88% of the total proved plus probable reserves with natural gas representing the remaining 12% (using a boe conversion ratio of six thousand cubic feet ("Mcf") to one barrel ("bbl")).
- Development inventory of approximately 90 locations – an eight year inventory at a planned pace of drilling ten to twelve wells per year.
- Long life reserves that typically have 70% of estimated recoverable hydrocarbons remaining after drilling cost payout.
- Reserve life index ("**RLI**") of 46.7 years, calculated on the basis of estimated proved plus probable reserves divided by current working interest production.
- Eagle has agreed to purchase the seller's remaining 7.5% working interest (the "Remaining Interest") in the properties within 12 months at fair market value. The terms of the Acquisition restrict the seller from, indirectly or directly, soliciting, negotiating or taking any other actions or steps in respect of a sale or possible sale of the Remaining Interest to any third party prior to April 30, 2013.

The Acquisition has the following anticipated benefits and associated upside potential

- Creates a new operational area, located in the Permian Basin, which diversifies Eagle's portfolio of petroleum assets.
- Increases Eagle's portfolio of low risk drilling locations by 3.5 times, from 36 to 126 locations. The leases comprising the Acquired Assets are predominantly held by production, allowing Eagle to proceed at its own development pace.

- Improves Eagle's overall RLI by approximately 90% to 15.3 years.
- Increases the Trust's enterprise value by approximately 50%, while maintaining a low-leverage balance sheet (debt to cash flow ratio under 0.5:1).
- Enables Eagle to increase Eagle's borrowing base under its credit facility to US$48.5 million from US$31 million.
- Is immediately accretive to the Trust's reserves per unit and net asset value per unit. Although slightly dilutive in the near term on a cash flow per unit and production per unit basis, distributions remain comfortably sustainable throughout 2012, at current cost and commodity price levels.
- The Acquisition will be accretive to cash flow per unit and production per unit when the estimated 2012 exit rate of approximately 1,000 boe/d is achieved, and becomes increasingly accretive as Eagle grows production.

The Offering

In conjunction with the Acquisition, Eagle has entered into an agreement with a syndicate of underwriters (the "**Underwriters**") led by Scotiabank pursuant to which the Underwriters have agreed to purchase, on a bought deal basis, 7,730,000 trust units at a price of Cdn$11.00 per Trust Unit, for aggregate gross proceeds of approximately Cdn$85,030,000 (the "**Offering**"). The Trust intends to use the net proceeds of the Offering, plus an advance of approximately US$28.8 million under its credit facility and approximately US$5.5 million of working capital to fund the Acquisition. The Acquisition and the Offering are expected to close on or about May 18, 2012 (the "**Closing**"). Closing of the Offering is subject to certain conditions including, but not limited to, the receipt of all necessary approvals, including the approval of the Toronto Stock Exchange and the securities regulatory authorities.

In addition, the Underwriters have been granted an over-allotment option, exercisable for a period commencing at Closing and ending 30 days following Closing, to purchase up to 1,159,500 additional Trust Units at a price of Cdn$11.00 per Trust Unit. If the over-allotment is fully exercised, gross proceeds from the Offering will be approximately Cdn$97,784,500.

Eagle's Credit Facility

Eagle expects to use the net proceeds from the Offering (assuming the over-allotment option has not been exercised), approximately $5.5 million of working capital and US$28.8 million from its existing credit facility to fund the purchase price of the Acquired Assets. The lender has approved an increase to the borrowing base of the credit facility from US$31 million to US$48.5 million and the amendment to the credit facility will be in place prior to completion of the acquisition. After the closing of the Acquisition, and assuming the over-allotment option has not been exercised, Eagle expects to have approximately US$19.7 million of undrawn capacity available under the credit facility. Eagle and its lender anticipate undertaking a mid-year redetermination of Eagle's borrowing base. In general terms, Eagle expects that the borrowing base will increase in the coming 18 months as Eagle continues to convert proved and probable undeveloped reserves to proved developed producing reserves through its ongoing drilling programs on both the Salt Flat assets and the Acquired Assets.

Sensitivities

The Trust's results and ability to generate sufficient amounts of cash to fund ongoing operations are affected by external market factors such as fluctuations in the prices of crude oil as well as movements in foreign-exchange rates. Changes in production also affect funds flow. Sensitivities to these factors are summarized below: (note that sensitivities to changes in natural gas prices, natural gas production and interest rates are not applicable since the Trust currently does not have any natural gas production or debt).

	Full year impact on ➔	**Funds flow from operations ($000's)**	**Funds flow from operations / unit** [1]
Gas price	+ USD $0.10/mcf Henry HUB	N/A	N/A
Oil price [2]	+ USD $1.00/bbl WTI	571	$ 0.02
Gas production	+1000 mcf/d	N/A	N/A
Oil production	+100 bbls/d	1,984	$ 0.10
Currency [2]	+CDN strengthen by $0.01	(427)	$ (0.01)
Interest Rate	+1% prime	N/A	N/A

Notes:

(1) Per unit figures are based on 18,673,432 weighted average basic units outstanding for the quarter ended March 31, 2012.

(2) Price and currency sensitivities are calculated assuming an average yearly production rate equal to year to date average sales volumes of 2,169 bbls per day.

Non-IFRS financial measures

The following table reconciles the non-IFRS financial measures "funds flow from operations" and "field netback" to "loss for the period", the most directly comparable measure in the Trust's consolidated financial statements:

		Three Months Ended March 31, 2012		**Three Months Ended March 31, 2011**
Loss	**$**	(952)	**$**	(1,911)
Add back (deduct) items not involving cash:				
Unit-based compensation		4,005		2,775
Unrealized risk management loss		930		1,414
Depletion, amortization and accretion		5,101		2,895
Finance expense		34		20
Funds flow from operations	**$**	**9,118**	**$**	5,193
Add back (deduct) items not directly related to field operations:				
Realized foreign exchange gain		(10)		(518)
Finance expense (cash portion)		27		4
Unit-based compensation (cash portion)		-		-
Risk management (gain) loss-realized		256		18
Administrative expenses		1,338		1,127
Field netback	**$**	**10,729**	**$**	**5,824**

No change in internal controls over financial reporting during the period January 1, 2012 to March 31, 2012

During the period beginning on January 1, 2012 and ended on March 31, 2012, there was no change in the Trust's internal controls over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trust's internal controls over financial reporting. It should be noted, that the Trust's control system, no matter how well designed, can provide only reasonable, but not absolute, assurance of detecting, preventing and deterring errors or fraud.

Note about forward-looking statements

Certain of the statements made and information contained in this MD&A are forward-looking statements and forward looking information (collectively referred to as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historic fact are forward-looking statements. The Trust cautions investors that important factors could cause the Trust's actual results to differ materially from those projected, or set out, in any forward-looking statements included in this MD&A.

In particular, and without limitation, this MD&A contains forward looking statements pertaining to the following:

- Eagle's 2012 capital budget and drilling plans;
- the Trust's expectation regarding its 2012 average working interest production, funds flow from operations, payout ratio, WTI pricing and operating costs;
- the Trust's expectations regarding the impact and benefit of the Acquisition on the Trust, including, but not limited to, the impact on its reserves per unit, net asset value per unit, cash flow per unit, production per unit, enterprise value and portfolio of low risk drilling locations;
- Eagle's expectation that production from the Acquired Assets will increase to approximately 1,000 boe/d by year end;
- the Trust's expectation that distributions on the Units will remain comfortably sustainable;
- the taxability of the Trust and the status of the Trust as a mutual fund trust and not a SIFT trust;
- management's objective to maintain a debt to cash flow ratio below 1.5 times; and
- the Trust's expectation regarding the RLI of the Acquired Assets and the impact of the Acquisition on Eagle's overall RLI.

With respect to forward-looking statements contained in this MD&A, assumptions have been made regarding, among other things:

- future oil and natural gas prices;
- future currency exchange and interest rates;
- the regulatory framework governing taxes in the US and Canada and the Trust's status as a "mutual fund trust" and not a "SIFT trust;"
- estimates of anticipated production from both the Salt Flat Field assets and the Acquired Assets, which estimates are based on the proposed drilling program with a success rate that, in turn, is based upon historical drilling success and an evaluation of the particular wells to be drilled;
- projected operating costs for both the Salt Flat Field assets and the Acquired Assets, which are based on historical information and anticipated increases in the cost of equipment and services
- future recoverability of reserves for both the Salt Flat Field assets and the Acquired Assets;
- future capital expenditures and the ability of the Trust to obtain financing on acceptable terms for its capital projects and future acquisitions;
- the Trust's 2012 capital budget, which is subject to change in light of ongoing results, prevailing economic circumstances, commodity prices and industry conditions and regulations;
- not including capital required to pursue future acquisitions in the forecasted capital expenditures; and
- the ability of the Trust to compete for new acquisitions.

The Trust's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included in the AIF:

- volatility of commodity prices;
- commodity supply and demand;
- fluctuations in currency and interest rates;
- inherent risks and changes in costs associated in the drilling and development of petroleum properties;
- unexpected operational delays and challenges
- access to drilling equipment on a timely basis and at reasonable prices;
- ultimate recoverability of reserves;

- timing, results and costs of drilling activities and resulting production;
- availability of financing and capital; and
- new regulations and legislation that apply to the Trust and the operations of its subsidiaries.

Additional risks and uncertainties affecting the Trust are contained in the AIF under the heading "Risk Factors".

As a result of these risks, actual performance and financial results in 2012 may differ materially from any projections of future performance or results expressed or implied by these forward-looking statements. New factors emerge from time to time, and it is not possible for management to predict all of these factors or to assess, in advance, the impact of each such factor on the Trust's business, or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward looking statement.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward looking statements will not occur. Although Management believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date the forward-looking statements were made, there can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Trust and its unitholders. The Trust does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise.

Note regarding barrel of oil equivalency

Eagle has adopted the standard of 6 Mcf to 1 bbl when converting natural gas to boe. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of six to one, utilizing a boe conversion ratio of 6 Mcf to 1 bbl would be misleading as an indication of value.

Eagle Energy Trust

Interim Condensed Consolidated Financial Statements
(in Canadian dollars) (unaudited)

For the three months ended March 31, 2012 and March 31, 2011

Eagle Energy Trust

Condensed Consolidated Balance Sheet

(Thousands of Canadian dollars) (unaudited)

	Note	March 31, 2012	December 31, 2011
ASSETS			
Current assets			
Cash		$ 10,155	$ 7,495
Trade and other receivables		6,093	5,585
Prepaid expenses		199	305
		16,447	**13,385**
Non-current assets			
Exploration and evaluation		83	119
Oil and gas properties	8	139,533	145,067
Property, plant and equipment		182	127
Other intangible assets		232	187
		140,030	**145,500**
Total Assets		**$ 156,477**	$ **158,885**
LIABILITIES			
Current liabilities			
Trade and other payables		4,734	5,926
Distributions payable	9	1,683	1,656
Unit-based payments	6	12,469	8,472
Risk management liability	3	1,433	503
		20,319	**16,557**
Non-current liabilities			
Other long term liabilities		7	-
Provision for liabilities and other charges		482	502
		489	**502**
Total Liabilities		**$ 20,808**	$ **17,059**
UNITHOLDERS' EQUITY			
Trust capital	10	171,200	168,175
Other reserves		(3,925)	(718)
Accumulated loss		(5,379)	(4,427)
Accumulated cash distributions	9	(26,227)	(21,204)
Total Unitholders' Equity		**135,669**	**141,826**
Total Liabilities and Unitholders' Equity		**$ 156,477**	$ **158,885**

The notes are an integral part of these condensed financial statements

See Note 13 "Commitments" and Note 14 "Subsequent events"

Eagle Energy Trust

Condensed Consolidated Statement of Loss and Statement of Comprehensive Loss

(Thousands of Canadian dollars) (unaudited)

	Note		**Three Months Ended March 31, 2012**		Three Months Ended March 31, 2011
Revenue	4	$	13,947	$	7,135
Cost of sales	5		8,297		4,201
Gross profit			5,650		2,934
Administrative expenses			1,361		1,126
Unit based compensation	6		4,005		2,775
Operating profit (loss)			**284**		**(967)**
Foreign exchange gain, net			10		518
Finance expense			(60)		(30)
Risk management loss	3		(1,186)		(1,432)
Loss before taxation			**(952)**		**(1,911)**
Loss for the period		**$**	**(952)**	**$**	**(1,911)**
Other comprehensive loss for the period					
Foreign currency translation loss			(3,207)		(3,795)
Total comprehensive loss for the period		**$**	**(4,159)**	**$**	**(5,706)**
Loss per unit during the period					
Basic	7		(0.05)		(0.11)
Diluted	7		(0.05)		(0.11)

The notes are an integral part of these condensed financial statements

Eagle Energy Trust

Condensed Consolidated Statement of Changes in Unitholders' Equity

For the three months ended March 31, 2012 and year ended December 31, 2011
(Thousands of Canadian dollars) (unaudited)

	Note	Number of Trust Units	Trust capital	Currency reserve	Accumulated loss	Accumulated Cash distributions	Deficit	**Total Unitholders' equity**
Balance at December 31, 2010		**17,624**	**159,577**	**(4,366)**	**(3,214)**	**(1,916)**	**(5,130)**	**150,081**
Loss for the period		-	-	-	(1,911)	-	(1,911)	(1,911)
Foreign currency translation gain		-	-	(3,795)	-	-	-	(3,795)
Total comprehensive income		-	-	(3,795)	(1,911)	-	(1,911)	(5,706)
Issuance of Trust capital		-	(115)	-	-	-	-	(115)
Unitholder distributions		-	-	-	-	(4,728)	(4,728)	(4,728)
		-	(115)	-	-	(4,728)	(4,728)	(4,843)
Balance at March 31, 2011		**17,624**	**159,462**	**(8,161)**	**(5,124)**	**(6,644)**	**(11,768)**	**139,532**
Balance at December 31, 2011		**18,544**	**168,175**	**(718)**	**(4,427)**	**(21,204)**	**(25,631)**	**141,826**
Loss for the period		-	-	-	(952)	-	(952)	(952)
Foreign currency translation gain		-	-	(3,207)	-	-	-	(3,207)
Total comprehensive income		-	-	(3,207)	(952)	-	(952)	(4,159)
Issuance of Trust capital	10	303	3,053	-	-	-	-	3,053
Trust unit issuance costs	10	-	(28)	-	-	-	-	(28)
Unitholder distributions	9	-	-	-	-	(5,023)	(5,023)	(5,023)
		303	3,025	-	-	(5,023)	(5,023)	(1,998)
Balance at March 31, 2012		**18,847**	**171,200**	**(3,925)**	**(5,379)**	**(26,227)**	**(31,606)**	**135,669**

The notes are an integral part of these condensed financial statements

Eagle Energy Trust

Condensed Consolidated Cash Flow Statement

(Thousands of Canadian dollars) (unaudited)

	Note	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Cash flows from operating activities			
Net cash generated by operating activities	11	**$ 7,511**	**$ 3,283**
Cash flows from investing activities			
Additions to exploration and evaluation		(83)	(150)
Additions to oil and gas properties		(2,475)	(5,334)
Additions to property, plant and equipment		(81)	(28)
Net cash used in investing activities		**$ (2,639)**	$ **(5,512)**
Cash flows from financing activities			
Proceeds from issuance of units		3,053	-
Trust unit issue costs		(28)	(115)
Cash distributions to unitholders		(4,997)	(5,068)
Deferred financing charges		(75)	-
Net cash used in financing activities		**$ (2,047)**	$ **(5,183)**
Net (decrease) increase in cash and cash equivalents		**2,825**	**(7,412)**
Effects of exchange rates on cash and cash equivalents		(165)	(686)
Cash at beginning of the period		7,495	31,731
Cash at end of the period		**$ 10,155**	**$ 23,633**

The notes are an integral part of these condensed financial statements

Eagle Energy Trust

Notes to Condensed Consolidated Financial Statements (unaudited)

For the three months ended March 31, 2012 and March 31, 2011
(in Canadian dollars)

1. Reporting entity / Structure of the Trust

Eagle Energy Trust's activities are restricted to owning property (other than real property or interests in real property), and it does not carry on business. Eagle Energy Trust's subsidiaries are in the business of acquiring, developing and producing petroleum reserves in the United States. Eagle Energy Trust was formed as an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta on July 20, 2010 and was settled with a 1/10 ounce gold coin and $200 from the initial unitholders. The beneficiaries of the Trust are the unitholders.

Throughout these notes to the condensed consolidated financial statements, Eagle Energy Trust and its subsidiaries are referred to collectively as the "Trust" or "Eagle" for purposes of convenience.

The strategy of the Trust is to invest in operating subsidiaries that will acquire on-shore petroleum reserves and production in certain regions of the United States. The Trust's subsidiaries do not intend to engage substantively in exploration activities. The Trust intends to make monthly distributions of a portion of its available cash to unitholders and use the remainder of its available cash to reinvest in its subsidiaries to fund growth through additional acquisitions and capital expenditures. Cash flow is provided to the Trust from properties owned and operated by an indirectly owned subsidiary of the Trust.

Operations officially commenced on November 24, 2010, concurrent with the closing of the Salt Flat Field acquisition.

The address of the Trust is: 9th Floor, 639-5th Avenue SW, Calgary, AB T2P 0M9.

2. Basis of preparation

Basis of accounting

The condensed consolidated financial statements were authorized for issue in accordance with a resolution of the Board of Directors made on May 10, 2012.

These condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including IAS 34, Interim Financial Reporting and have been prepared following the same accounting policies as the annual audited IFRS Consolidated Financial Statements for the year ended December 31, 2011, except for income tax expense for an interim period which is based on an estimated average annual effective income tax rate. The condensed consolidated interim financial statements should be read in conjunction with the annual financial statements for the year ended December 31, 2011, which have been prepared in accordance with IFRS as issued by the IASB.

3. Financial risk management

The Trust's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about significant changes in the Trust's exposure to each of the above risks since the year ended December 31, 2011.

Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Trust's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters while optimizing the return.

The Trust may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand.

The Trust enters into certain financial derivative instruments periodically to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Trust does not apply hedge accounting for these contracts. The Trust's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Trust, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts.

As at March 31, 2012 the Trust has entered into the following financial contracts to mitigate the effects of fluctuating prices on a portion of its production as follows:

1. A costless collar contract for 200 bbls of oil per day with a May 2011 through April 2012 term at a floor of $US 88.00 per barrel and a ceiling of $US 107.55 per barrel.
2. A fixed contract to sell 100 bbls of oil per day with a May 2011 through April 2012 term at a price of $US 101.00 per barrel.
3. A fixed contract to sell 200 bbls of oil per day with a November 2011 through October 2012 term at a price of $US 91.00 per barrel.
4. A costless collar contract for 500 bbls of oil per day with a January 2012 through December 2012 term at a floor of $US 92.00 per barrel and a ceiling of $US 105.00 per barrel.
5. A costless collar contract for 300 bbls of oil per day with a May 2012 through April 2013 term at a floor of $US 95.00 per barrel and a ceiling of $US 108.25 per barrel

Summary of Unrealized Risk Management Positions as at March 31, 2012

	Volume	*Measure*	*Beginning*	*Term*	*Floor $US*	*Ceiling $US*	*Fair Value $CA*
Oil Fixed Price							
NYMEX (i)	200	bbls/d	May-11	Apr-12	88.00	107.55	$ (3)
NYMEX (ii)	100	bbls/d	May-11	Apr-12	101.00	101.00	(23)
NYMEX (ii)	200	bbls/d	Nov-11	Oct-12	91.00	91.00	(661)
NYMEX (i)	500	bbls/d	Jan-12	Dec-12	92.00	105.00	(532)
NYMEX (i)	300	bbls/d	May-12	Apr-13	95.00	108.25	(214)
							$ (1,433)

(i) Represents costless collar transactions created by buying puts and selling calls (WTI reference prices).
(ii) Represents a fixed price financial swap transaction with a set forward sale price (WTI reference prices).

Earnings Impact of Realized and Unrealized Gain (Loss)
For the three months ended March 31, 2012

$000's	Realized Gain (Loss)	Unrealized Gain (Loss)	Total Net Gain (Loss)
Net effect - risk management	**$ (256)**	**$ (930)**	**$ (1,186)**

4. Operating segments

The operations of the Trust comprise one operating segment: oil and gas exploration, development and the sale of hydrocarbons and related activities. All of the Trust's assets and liabilities, income and expenses relate to this segment and the relevant disclosures have been made elsewhere in these financial statements.

Geographical information

The Trust's operational activities are wholly focused in the continental United States, currently in the state of Texas, and are supported by offices in Houston and Luling, Texas. The Trust's head office is in Calgary, Alberta. All inter-segment and geographical transactions have been eliminated in consolidation.

Revenue

All of the Trust's revenue from external customers is derived from its operations in the United States. Revenue is presented net of royalties as noted in the following table.

$000's	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Revenue before royalties	$ 19,174	$ 9,864
Royalties	(5,227)	(2,729)
	$ 13,947	**$ 7,135**

Non-Current assets

All of the Trust's non-current assets are within the United States.

5. Cost of sales

$000's	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Operating costs related to the field	$ 3,219	$ 1,311
Depreciation, depletion and amortization	5,078	2,890
	$ 8,297	**$ 4,201**

6. Unit-based payments

The following table reconciles unit-based compensation expense.

$000's	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	
Units issued on performance option surrender	711	634	Note 10 (a)
Restricted unit rights	1,457	825	Note 10 (b)
Unit options	1,594	1,316	Note 10 (c)
Phantom unit rights	243	-	Note 10 (d)
Total unit-based compensation expense	**$ 4,005**	**$ 2,775**	

Note (a)

Units issued upon surrender of performance options

At March 31, 2012, December 31, 2011 and March 31, 2011, there were 387,500 units outstanding.

At March 31, 2012, $2,841,615 (December 31, 2011 – $2,130,831, March 31, 2011 - $nil) was included in trade and other payables and $nil (December 31, 2011 - $nil, March 31, 2011 - $840,332) was included in other long-term liabilities relating to these units.

At March 31, 2012, the fair value of the units was assumed to be equal to the March 31, 2012 closing price of $11.24 per unit (December 31, 2011 - $10.05 per unit, March 31, 2011 - $11.89 per unit).

Note (b)

Cash settled Restricted Unit Rights (RURs) issued upon surrender of performance options

At March 31, 2012, December 31, 2011 and March 31, 2011, there were 775,000 RURs outstanding.

At March 31, 2012, $3,827,586 (December 31, 2011 - $2,370,407, March 31, 2011 - $nil) was included in trade and other payables and $nil (December 31, 2011 - $nil, March 31, 2011 – $988,044) was included in other long term liabilities relating to these RURs.

At March 31, 2012, the Black-Scholes valuation model was used to determine the fair value of the RURs issued by the Trust. The fair value of the RURs was estimated using the following inputs:

	March 31, 2012	December 31, 2011	March 31, 2011
Fair value at the balance sheet date	$ 7.57	$ 5.59	**$ 6.99**
Volatility	35%	35%	33%
Life of restricted unit rights	8.8 years	9.0 years	9.8 years
Risk-free interest rate	2.13%	1.98%	3.2%

A forfeiture rate of 5% was used and, due to the limited history of the Trust, this figure is an estimated expected rate.

Note (c)

Unit option plan

At March 31, 2012 and December 31, 2011 there were 1,706,000 options outstanding. The weighted average exercise price at March 31, 2012 was $8.62 per option (December 31, 2011 – $8.88 per option). At March 31, 2011, there were 1,342,500 options outstanding with a weighted average exercise price of $9.76.

At March 31, 2012, $5,347,411 (December 31, 2011 - $3,801,767, March 31, 2011 - $883,420) was included in trade and other payables and $nil (December 31, 2011 - $nil, March 31, 2011 - $736,183) was included in other long-term liabilities relating to this option plan.

The closing trading price of the Trust's units at March 31, 2012 was $11.24 per unit (December 31, 2011 - $10.05 per unit, March 31, 2011 - $11.89 per unit). At March 31, 2012, the Black-Scholes valuation model was used to determine the fair value of the options issued by the Trust. The fair value of the options was estimated using the following inputs:

	March 31, 2012	December 31, 2011	March 31, 2011
Fair value at the balance sheet date	$ 5.73	$ 4.73	$ 6.11
Unit price	$ 11.24	$ 10.05	$ 11.89
Exercise price	$ 8.62	$ 8.88	$ 9.76
Volatility	35%	35%	33%
Option life	8.9 years	9.1 years	9.7 years
Distributions – none estimated, declining strike price feature	0%	0%	0%
Risk-free interest rate	2.13%	1.98%	3.2%

A forfeiture rate of 5% was used and due to the limited history of the Trust, this figure is an estimated expected rate. This estimate will be adjusted to the actual forfeiture rate.

Note (d)

Phantom unit rights (PUR) plan

At March 31, 2012 and December 31, 2011 there were 185,000 phantom unit rights outstanding. At March 31, 2011, there were nil phantom unit rights outstanding, since the plan was implemented June 14, 2011.

At March 31, 2012, $460,188 (December 31, 2011 - $217,620, March 31, 2011 - $nil) was included in trade and other payables and $7,127 (December 31, 2011 - $nil, March 31, 2011 - $nil) was included in other long-term liabilities relating to the PUR plan.

At March 31, 2012, the Black-Scholes valuation model is used to determine the fair value of the PURs issued by the Trust. The fair value of the PURs was estimated using the following weighted average inputs:

	March 31, 2012	December 31, 2011
Fair value at the balance sheet date	$ 6.15	$ 4.76
Volatility	35%	35%
Life of restricted unit rights	9.3 years	9.5 years
Risk-free interest rate	2.13%	1.98%

A forfeiture rate of 5% was used and, due to the limited history of the Trust, this figure is an estimated expected rate.

7. Loss per unit

$000's	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Loss attributable to unitholders	$ (952)	$ (1,911)
Weighted average number of units outstanding (basic and diluted)	18,673	17,624
Basic and diluted income (loss) per unit	**$ (0.05)**	**$ (0.11)**

Calculation

Basic income per unit is calculated by dividing the income attributable to owners of the Trust by the weighted average number of units outstanding during the period. Diluted income per unit is calculated using the income for the period divided by the weighted average number of units outstanding assuming the conversion of potentially dilutive equity instruments outstanding.

Per unit amounts

Diluted income per unit is equal to basic income per unit as it was determined that the conversion of potentially dilutive equity instruments would be anti-dilutive. Excluded from the three months ended March 31, 2012 and March 31, 2011 units outstanding is the effect of the 387,500 units issued to certain directors, Management and a consultant on the surrender of previously granted performance options as well as 1,706,000 (March 31, 2011 – 1,342,500) options as their effect is anti-dilutive. Refer to "Trust capital" note 10.

8. Oil and gas properties

$000's	Developed oil & gas assets	Production facilities and equipment	Capitalized future decom-missioning costs	Total
Cost				
At December 31, 2011	$ 154,365	$ 3,356	$ 491	$ 158,212
Additions	(1,633)	1,203	(25)	(455)
Transfers from exploration and evaluation	-	-	-	-
At March 31, 2012	**$ 152,732**	**$ 4,559**	**$ 466**	**$ 157,757**
Accumulated depreciation				
At December 31, 2011	$ (12,555)	$ (590)	$ -	$ (13,145)
Charge for the period	(4,628)	(451)	-	(5,079)
At March 31, 2012	**$ (17,183)**	**$ (1,041)**	**$ -**	**$ (18,224)**
Net book value				
At December 31, 2011	$ 141,810	$ 2,766	$ 491	$ 145,067
Net change	(6,261)	752	(25)	(5,534)
At March 31, 2012	**$ 135,549**	**$ 3,518**	**$ 466**	**$ 139,533**

The Trust does not capitalize general and administrative costs. Future development costs related to proved plus probable reserves of $52,382,132 (December 31, 2011 - $54,982,000) were included in the depletion calculation.

9. Distributions payable

$000's	March 31, 2012	December 31, 2011	Cumulative
Beginning balance	$ 1,656	$ 1,916	$ -
Distributions declared	5,024	19,287	26,227
Less distributions paid	(4,997)	(19,547)	(24,544)
Outstanding distributions declared and payable	**$ 1,683**	**$ 1,656**	**$ 1,683**

Distributions are declared and paid monthly. The outstanding balance at March 31, 2012 represents the distribution declared March 15, 2012 and paid April 23, 2012. The outstanding balance at December 31, 2011 represents the distribution declared December 15, 2011 and paid January 23, 2012.

10. Trust capital

Trust units outstanding	**March 31, 2012**			**December 31, 2011**		
$000's	**Number of units (000's)**		**Amount $000's**	**Number of units (000's)**		**Amount $000's**
Beginning balance	18,544	$	168,175	17,624	$	159,577
Issuance of Trust capital pursuant to DRIP	303		3,053	920		8,961
Reclass from unit based compensation for option exercise	-		-	-		49
Trust Unit issuance costs	-		(28)	-		(412)
Ending balance	**18,847**	**$**	**171,200**	**18,544**	**$**	**168,175**

Trust units issued, but not classified as outstanding

Refer to note 6 "Unit-based payments". The 387,500 units issued to certain directors, management and a consultant on the surrender of previously granted performance options have been excluded from units outstanding as a result of IFRS principles which exclude units due to the performance conditions that have to be met in order for the units to be released from escrow.

11. Cash generated from operations

$000's		**Three Months Ended March 31, 2012**		**Three Months Ended March 31, 2011**
Income (loss) for the period	**$**	(952)	**$**	(1,911)
Adjustments for:				
Depreciation, depletion and amortization		5,101		2,895
Unit-based compensation		4,005		2,775
Unrealized risk management loss		930		1,414
Finance expense		34		19
		9,118		**5,192**
Changes in working capital:				
Trade and other receivables		(616)		(2,909)
Prepaid expenses		102		(89)
Trade and other payables		(1,093)		1,089
		(1,607)		**(1,909)**
Cash (used in) generated from operations		7,511		3,283
Income taxes paid		-		-
Net cash generated by operating activities	**$**	**7,511**	**$**	**3,283**

Summary of non-cash items

$000's	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Operating cash flow		
Unit-based compensation	$ 4,005	$ 2,775
Distributions payable-declared not yet paid	1,683	1,576
Unrealized risk management loss	1,433	1,414
Investment activities		
Depreciation, depletion and amortization	5,101	2,895
Provision for decommissioning costs	15	50
Accretion of decommissioning provision	4	2
Financing activities		
Finance expense-amortization of deferred financing costs	29	18
Distributions accrued-declared not yet paid	(1,683)	(1,576)

12. Related party disclosures

The Trust has no party holding voting control.

Key management personnel

Key management personnel consist of the Chief Executive Officer (CEO), Chief Operating Officer (COO), Chief Financial Officer (CFO), and the Directors.

Intercompany transactions

There are certain intercompany transactions among the subsidiaries comprising these consolidated financials of the Trust. These transactions have been eliminated in consolidation.

Head office lease in Calgary, Alberta

The Trust sub-leases office space along with furniture and equipment from a company of which a director of the Administrator of the Trust is the President and Chief Operating Officer. The terms of the agreement are recorded at the exchange amount. The monthly rent rate is $8,500, which approximates market value. Refer to "Commitments" note 13 regarding operating lease commitments.

No amounts were owing to this related party as at March 31, 2012 and December 31, 2011. For the three months ended March 31, 2012 administrative expenses included $25,500 (March 31, 2011 - $24,000) for amounts billed from this related party.

13. Commitments

Operating lease commitment – head office lease in Calgary, Alberta

The initial term of the sub-lease agreement was for six months from January 1, 2011 until June 30, 2011. On July 25th, 2011, the sub-lease agreement was renewed for an additional 6 month period from August 1, 2011 to January 31, 2012 with a monthly rent rate of $8,500. Thereafter, the agreement automatically rolls over on a monthly basis, unless either party serves a 30 day notice of termination. Therefore, the agreement is cancellable any time after the end of the term if notice is provided. Future minimum lease payments during the additional six month term of the sub-lease were $51,000, with $nil remaining as at March 31, 2012.

Operating lease commitment – office lease in Houston, Texas

The agreement was entered into on April 1, 2011, and has an approximate 30 month term from April 7, 2011 through September 30, 2013. Future minimum lease payments during the term of the sub-lease approximate $US 338,400, with 18 months and approximately $US 203,000 remaining at March 31, 2012. In $CA the remaining future minimum lease payments approximate $202,600 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9975.

Operating lease commitment – office lease in Luling, Texas

The agreement was entered into on August 15, 2011, and has an approximate 12 month term from August 15, 2011 through August 31, 2012. Future minimum payments during the term of the sub-lease are $US 20,600, with $US 8,300 remaining at March 31, 2012. In $CA, the remaining future minimum lease payments approximate $ 8,200 translated at the exchange rate in effect at the balance sheet date of $US 1 equal to $CA 0.9975.

Drilling rig commitment – nine wells

The Trust, through its operations in the Salt Flat Field, entered into a nine well drilling rig commitment agreement. At March 31, 2012, no wells have been drilled under the agreement. Future minimum payments are estimated to be approximately $US 1,100,000 which is 100% of the commitment. The net commitment to the Trust based upon its approximate 80% interest equates to $US 880,000. In $CA the net future commitment approximates $878,000 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9975.

Settlement agreement

The Trust, through its operations in the Salt Flat Field, signed a settlement agreement with a third party to reimburse them for certain future costs relating to damages to the producing formation of a nearby well. Future costs associated with this settlement agreement are estimated to be $US 75,000, which is 100% of the commitment. The net commitment to the Trust, based upon its 80% interest, equates to $US 60,000. In $CA the net future commitment approximates $59,900 translated at the exchange rate in effect at the balance sheet date of $US 1.00 equal to $CA 0.9975.

14. Subsequent events

Operating lease extension – office lease in Luling, Texas

On April 24, 2012, Eagle gave written notice to extend the term of the lease for one additional term of 36 months.

Commodity Hedging

On May 1, 2012, the Trust entered into two financial contracts to further mitigate the effects of fluctuating prices on a portion of its production as follows:

(a) A fixed contract to sell 200 bbls of oil per day with a January 2013 through April 2013 term and 500 bbls of oil per day with a May 2013 through December 2013 term, at a price of $US103.45 per barrel.

(b) A fixed contract to sell 400 bbls of oil per day with a January 2014 through December 2014 term, at a price of $US98.00 per barrel.

Acquisition of Producing Light Oil Assets in the Permian Basin, Texas, Bought Deal Trust Unit Financing and Increase in Credit Facility

On May 3, 2012, the Trust announced it had signed a purchase and sale agreement to acquire, indirectly through its wholly-owned subsidiary, 92.5% of the seller's 99% interest in certain Permian Basin oil and natural gas properties and related assets located in the State of Texas for a purchase price of US$113,369,688, subject to closing adjustments. In connection with this, the Trust has filed a preliminary short form prospectus qualifying the distribution of 7,730,000 trust units at a price of $11.00 per unit. The Trust intends to use the net proceeds of the offering, plus an advance of approximately US$28.8 million under its credit facility and approximately US$5.5 million of working capital to fund the acquisition. In addition, the Trust's lender has approved an increase in the borrowing base of the credit facility to US$48.5 million from US$31 million. The amendment to the credit facility will be in place prior to completion of the acquisition.